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# Demand Elasticity and Market Power in the Spanish Electricity Market.[1]

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**Abstract**

In this paper we check whether generators' bid behavior at the Spanish wholesale electricity market is consistent with the hypothesis of profit maximization on their residual demands. Using OMEL data, we find the arc-elasticity of the residual demand around the system marginal price. The results suggest that the larger firms are not actually profit-maximizing on their residual demands while smaller generators' behavior is consistent with profit maximization. We argue how the regulatory environment may drive these results. Finally, we repeat the analysis for the first session of the intra-day market where presumably firms may not have the same incentives as in the day-ahead market.

*JEL: L11, L13, L51*

*Keywords: market power, electricity market, residual demand elasticity, profit maximization*

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# 1 Introduction

The Spanish spot market for electricity was introduced in 1998. As in many other electricity markets, there is a high concentration index together with an inelastic demand, and these features suggest that firms will use their market power to set prices well above costs. However, depending on other market conditions; electricity auction rules, or incentives provided by the regulator, concentration coupled with a low demand elasticity may give rise to higher or lower margins. Wolfram (1999) found that for the British market prices were much closer to marginal cost than most theories predicted, although she also finds some evidence of strategic capacity withholding. Explanations for the restrained price levels were financial contracts between the suppliers and their customers,[1] threat of entry and threat of regulatory intervention in the market.[2]

In this paper we explore first whether generators' bidding behavior at the Spanish wholesale market is consistent with profit maximization on the residual demand. We obtain the hourly residual demand for each generator and compute both the revenue-maximizing price-quantity pairs as well as the profit-maximizing price-quantity pairs. For the larger generators, these prices turn out to be consistently higher than the observed prices, whereas for smaller generators the differences are not significant.

Hortacsu and Puller (2004) have analyzed competition on the newly deregulated electricity market in Texas. They use data on demand, firm level bids and marginal cost and compare actual bids to theoretical ex-post optimal bids; their results indicate that the largest seller offered bids close to ex-post optimal bids, while smaller sellers seem to deviate from optimal behavior. Wolak (2003) measured unilateral market power for the California real-time energy market using measures of the inverse of the elasticity of residual demand. For the Australian electricity market, Wolak (2000) studied the impact of financial hedge contracts on generators' bidding behavior.

Besides market concentration and demand elasticity, there are other features of the Spanish wholesale market which could potentially affect firms' incentives for price setting. In the Spanish pool, generators get subsidies (CTCs, costs of transition to competition) and the way those subsidies are distributed affects firms' incentives to raise prices. Capacity payments may also affect the generators' incentives. A third factor is vertical

[1] See Green (1999) on contracts for differences.

[2] However, Newbery (2002) argues that many European countries lack the necessary regulatory power to mitigate generator market power.

integration. The Spanish electricity market is vertically integrated, so that larger generators are also large buyers in the pool. This feature might also be a significant factor mitigating the incentives for firms to keep pool prices high.[3] Unlike other electricity markets, hedge contracts are quantitatively unimportant in the Spanish market. All these market features affect the market power that firms will effectively exert so that the observed price cost margin, the *efective* market power, will be determined not only by market concentration and demand elasticity but also by regulatory rules, vertical integration and other factors.

It is difficult to measure how these factors will affect price-cost margins. Our purpose in this paper is to measure each generator's *potential* market power, defined here as the price-cost margin compatible with profit maximization: the inverse of the elasticity of the residual demand. In fact, the comparison between actual price-cost margins and the Lerner index compatible with profit maximization would give us an idea of the importance of other factors apart from demand elasticity or supply concentration.

The paper is organized as follows. Section 2 presents a model for the optimal bidding behavior of the generators at the pool. Since bids are short-lived in the Spanish market and generators are allowed to present up to 25 price-quantity pairs for each production unit, the rules allow enough flexibility so that the equilibrium price and quantity sold should be ex-post optimal. Section 3 describes the empirical implementation. On sections 4 and 5 we check whether actual bids match that optimal bidding behavior. First we find a lower bound for the pool's hourly price when generators maximize revenues on their residual demand. Then we calculate the ex-post optimal price. This price is decreasing over time for large generators due to the entry of new competitors in the market, on the supply side, and the entry of new consumers bidding, on the demand side (demand elasticity has been increasing over time). Section 6 concludes.

## 2 Profit maximization hypothesis

In the Spanish pool, firms submit short-lived bids for each plant (the bids for each of the 24 hours of the following day may be different). Aggregating the bids of all plants under the ownership of a generator we get its hourly supply schedule. Generators may not know for sure their residual demand, although uncertainty cannot be very large.[4]

[3] See Kühn and Machado (2004) for an analysis of vertical integration in the Spanish wholesale market.

[4] García-Díaz and Marin (2003) argue that with short-lived bids the degree of uncertainty is very low.

To maximize expected profits, for each possible residual demand realization, a generator should offer an amount such that marginal revenue equals marginal cost. The pair $(q, p)$ so determined should be a point in its supply schedule. This procedure can continue as long as the number of possible realization of residual demand is not higher than the number of steps in the supply function (see Wolak, 2000, for the regularity conditions that the distribution of the residual demand curve should satisfy)[5]. Then, the expected profit maximizing supply schedule should pass through all ex-post profit maximizing price and quantity pairs.

The implication is that for each realization of residual demand, bids will make marginal revenue equal to marginal cost. Tahe hour $h$, then:

$$L_i = \frac{p_h - C'_{ih}}{p_h} = \frac{1}{\varepsilon_{ih}} \tag{1}$$

where $p_h$ is the equilibrium price in hour $h$, $C'_{ih}$ is the marginal cost for firm $i$ at hour $h$, $\varepsilon_{ih}$ is the elasticity of the residual demand faced by firm $i$ at hour $h$, and $L_i$ denotes the Lerner index for each generator $i$. Note that if (1) did not hold for generator $i$, then firm $i$ could change its bid and increase its profits.

## 3 Empirical implementation

In the Spanish day-ahead market for electricity qualified buyers and sellers of electricity present their offers (before 11 a.m.) for each hour of the following day.

Sellers in the pool present bids consisting of up to 25 different prices and the corresponding energy quantities for each of the 24 periods and for each generating unit they own; the prices must be increasing.[6] If no restriction is included in the offer this is called a 'simple offer'. A seller may also present a 'complex offer' which may include indivisibility conditions, a minimum revenue condition, production capacity variation (load gradient conditions) and scheduled stop conditions. The pool administrator consolidates

[5]From his analysis of the Australian market and the California market Wolak (2003) concludes that firms were not overly constrained by the market rules from setting the profit maximizing price. The Spanish pool is even less contrained: for each generating unit the supply schedule may have 25 steps, instead of 10, and prices may be changed on an hourly basis.

[6]According to the Electricity Market Activity Rules, p. 6, generators "shall be required to submit electric power sale bids to the market operator for each of the production units they own for each and every one of the hourly scheduling periods."

the sales bids for each hourly period to generate an aggregate supply curve.

Qualified buyers in the pool present offers.[7] Purchase bids state a quantity and a price of a power block and there can be as many as 25 power purchasing blocks for the same purchasing unit, with different prices for each block; the prices must be decreasing. The pool administrator constructs an aggregate demand with these offers.

In a session of the day-ahead market the pool administrator combines these offers matching demand and supply for each of the 24 hourly periods and determines the equilibrium price for each period (the system marginal price) and the amount traded. After this matching is settled, the pool administrator evaluates the technical feasibility of the assignment; if the required technical restrictions are met then the program is feasible; if not, some previously accepted offers are eliminated and others included to obtain a feasible assignement. There is also an intra-day market to make any necessary adjustments between demand and supply.

Table 1 summarizes the total capacity owned as well as the share of total generation, by company and type of technology in 2004.

**Table 1. Generation Capacity by Type of Technology and Firm (MW)[1]**

| | EN | IB | UF | HC | VI | GN | RP | Others | TOTAL |
|---|---|---|---|---|---|---|---|---|---|
| Nuclear | 3574.6 | 3254.7 | 740.6 | 165.2 | 0 | 0 | 0 | 0 | 7735.1 |
| Coal-burning | 5519.7 | 1217 | 2035 | 625 | 867.8 | 0 | 0 | 0 | 10234.5 |
| Oil-fired | 2659 | 3193 | 770 | 887 | 753 | 0 | 0 | 0 | 8262 |
| Combined cycle | 1327.1 | 2637.2 | 1200 | 413.4 | 13.4 | 1600 | 200 | 2498.9 | 9890 |
| Hydroelectric | 5366.6 | 8372.4 | 1678.3 | 410.3 | 629 | 0 | 0 | 9 | 16465.8 |

[1]Renewable resources not included. Source: OMEL, own calculations.

Two companies, *Endesa* (EN) and *Iberdrola* (IB), own the majority of generating capacity, while *Unión Fenosa* (UF) and *Hidrocantábrico* (HC) are smaller competitors; all are private companies and each owns nuclear, thermal plants and hydroelectric units.

[7]From January 1st 2003, all buyers of electricity are considered qualified buyers. Before that date qualified buyers were those with consumption greater or equal to 1 GWh per year. The required consumption has decreased over time from 5GWh (December 1998) to 3GWh (April 1999), to 2GWh (July 1999) and to 1 GWh (October 1999).

Capacity has remained the same in coal-burning and oil-fired plants. There has only been addition of new capacity in combined cycle plants, and also in renewable resources. At the beginning of 2002, EN sold a small part of its capacity, *Viesgo*, to the Italian company *ENEL*, which has become the fifth competitor in the market. During 2002 and 2003 there has been entry in small scale (mainly *Repsol* and *Gas Natural*).

Figure 1 illustrates a typical demand and supply functions.

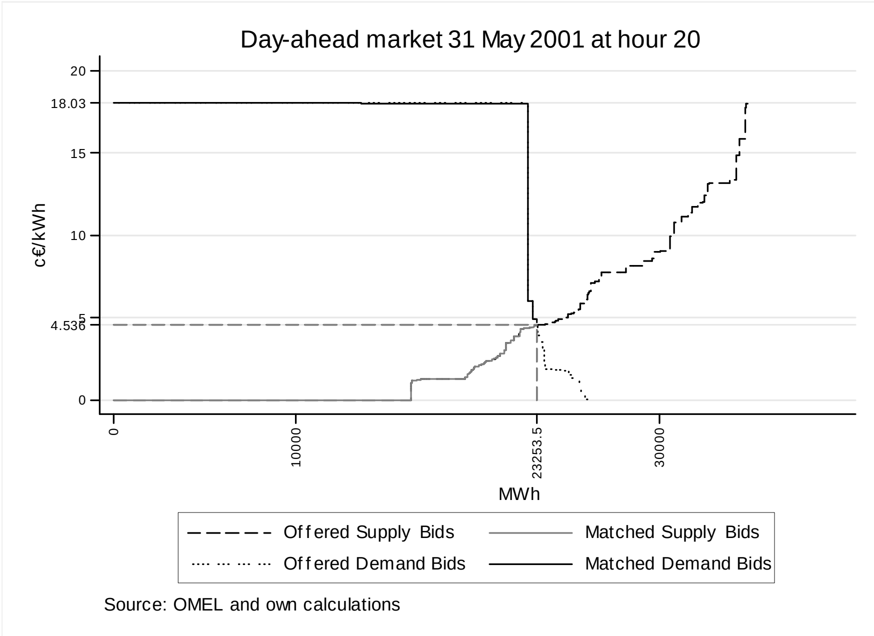



Figure 1

The system marginal price is 4.536 c€/kWh and the market clearing quantity is 23253.5 MWh. Note that there is a horizontal segment which mostly corresponds to the electricity demand by final consumers paying a regulated tariff. Since demand for those consumers cannot react to pool prices, bids for this consumption are made at the price cap, 18.030 c/kWh.

Other consumers however choose to present bids with the corresponding demand price. It is this part of demand which is of interest in this paper since we are trying to relate elasticity of demand and market power. For this reason we have ignored the horizontal initial segment of demand and focus on the price elastic segment. To do that we just change the origin, for the demand and supply schedules, to the first bid at a price lower than 18 c€/kWh. In Figure 1, the new origin would be at around 9000 MWh.

For each generator $i$ we need to calculate the value of elasticity of residual demand evaluated at the equilibrium price, $\varepsilon_i^r(p_h)$ for each hour $h$. We have data on individual hourly bids for each plant. First we add the bids for all plants under the ownership of a given generator to obtain the supply schedule of each generator $i$ for hour $h$. Demand bids are also available so that we have aggregate market demand for each hour $h$.

The hourly residual demand for $i$ is calculated by substracting from the aggregate demand the supply of all generators but $i$. This residual demand schedule will be denoted $D_i^r(p)$.

To compute the slope of the residual demand around the equilibrium price (calculated according to the market rules), we find the closest price above $p_h$ such that the residual demand is lower than the value at $p_h$ and denote that price $\bar{p}_h$. Similarly, we find the closest price below $p_h$ such that the residual demand is higher than the value at $p_h$ and denote that price $\underline{p}_h$. Then, we can calculate the arc elasticity of residual demand for generator $i$ for each hour $h$ as:

$$\varepsilon_i^r(p_h) = -\frac{D_i^r(\bar{p}_h) - D_i^r(\underline{p}_h)}{\bar{p}_h - \underline{p}_h} \frac{\bar{p}_h + \underline{p}_h}{D_i^r(\bar{p}_h) + D_i^r(\underline{p}_h)} \tag{2}$$

Another possibility is to fix the length $x$ of the arc (for example $\pm 10$ MW) and compute the price $\bar{p}_h$ such that residual demand is lower in an amount $x$ and the price $\underline{p}_h$ such that residual demand is higher in an amount $x$. We will use this procedure for several values of $x$ to compute the arc elasticity.

The data consists of hourly demand and supply bids for each agent and for each production and demand unit, in the day-ahead electricity wholesale market from May 2001 until December 2004. The hours are classified in peak, off-peak 1 and off-peak 2 hours (high, low and intermediate demand, respectively).[8]

We obtain the time series of inverse elasticities for each firm; EN, IB, UF, HC, and VI. We have the following time series: the equilibrium prices $p_h$,[9] $\bar{p}_h$, $\underline{p}_h$, and for each

[8] Data are available from May 2001. Following a pool administrator classification, data are divided into three categories:

Peak demand hours: From 16:00 to 22:00 week days (excluding holidays) in November, December, January, and February. From 9:00 to 15:00 week days in March, April, July, and October.

Off-peak 1 demand hours: From 0:00 to 8:00 every day of the year, plus Saturdays, Sundays, and holidays. August is also included.

Off-peak 2 demand hours: From 6:00 to 16:00 and from 22:00 to 00:00, week days in November, December, January, and February. From 8:00 to 9:00, and from 15:00 to 00:00, week days in March, April, July, and October. From 8:00 to 00:00 week days in May, June, and September.

[9] We use equilibrium prices before and after technical restrictions. On the other hand, the market

generator $i$, $D_i^r(\bar{p}_h)$, $D_i^r(\underline{p}_h)$. From expression (2) we calculate the hourly elasticity for each generator $\varepsilon_{ih}^r$, and compute the inverse $\frac{1}{\varepsilon_{ih}^r}$. Since hourly deviations from the profit maximization condition (1) are likely, we focus on the average values.

Table 2 summarizes the annual weighted average $\frac{1}{\varepsilon_{ih}^r}$ for the five largest generators from 2001,to 2004 for three different choices of the arc: ±0.1MWh, ±1MWh and ±10MWh.[10]

**Table 2: Inverse elasticity of residual demand day ahead market**

| Arc | YEAR | Firm | | | | |
|---|---|---|---|---|---|---|
| | | EN | IB | UF | HC | VI |
| | 2001 | 9.36 | 6.19 | 0.29 | 0.17 | |
| $\pm 0.1MWh$ | 2002 | 10.26 | 15.87 | 0.32 | 0.19 | 0.21 |
| | 2003 | 4.33 | 2.65 | 0.38 | 0.24 | 0.11 |
| | 2004 | 6.65 | 0.84 | 0.33 | 0.49 | 0.09 |
| | 2001 | 1.81 | 1.88 | 0.27 | 0.17 | |
| $\pm 1MWh$ | 2002 | 1.28 | 2.03 | 0.29 | 0.19 | 0.11 |
| | 2003 | 1.48 | 1.07 | 0.31 | 0.23 | 0.1 |
| | 2004 | 1.69 | 0.53 | 0.27 | 0.21 | 0.07 |
| | 2001 | 1.57 | 1.44 | 0.26 | 0.15 | |
| $\pm 10MWh$ | 2002 | 1.21 | 1.76 | 0.28 | 0.18 | 0.11 |
| | 2003 | 1.34 | 0.91 | 0.29 | 0.22 | 0.09 |
| | 2004 | 1.6 | 0.5 | 0.26 | 0.2 | 0.07 |

Table 2 suggests that the behavior of the two largest generators is not consistent with the expected profit maximization hypothesis since we obtain inverse elasticities of residual demand above one, regardless the type of hour and time period. There might be several explanations why large generators do not submit profit maximizing bids. Before turning to some of these explanations, we compute in the next two sections the revenue

operator sometimes rejects demand bids at a high price because they are unfeasible given the capacity restrictions of the interconnections with the neighbor countries (there is a rationing procedure to assign the interconnection capacity among bidders).

[10] The results for GN and RP do not differ much from VI since the capacity of generation is rather small.

maximizing bids and the profit maximizing bids to see whether these are far away from the actual bids.

## 4 Revenue-maximizing price and quantity

We look for the price-quantity pair such that it maximizes the revenue of the firms, where the revenue is defined over the residual demand under capacity constraints. This is a first approach and later on we approximate the profit- maximizing prices for each firm. The revenue-maximizing prices are a lower bound for the optimal prices and have the advantage of being independent of cost estimations. When there are generation costs, prices can only be above the revenue-maximizing prices. The unique constraint we must include is that the revenue-maximizing quantity is not above the total capacity of generation available by the firm at any time period. Thus for each firm $f$ and hour $h$, we compute the solution to the following problem,

$$\begin{array}{cc} \max_{p_h^f} & \left[p_h^f D_h^{r,f}\left(p_h^f\right)\right] \\ \text{s.t.} & q_h^x \leq K^x \text{ for } x = \{nu, co, fg, cc, hy\} \end{array}$$

Since we have demand schedules, the residual demands for each firm are also schedules, therefore the maximization problem may not have solution or even if it does, it may not be unique. We apply standard kernel estimation techniques to smooth the revenue schedules and obtain a global maximum. Thus we compute the weighted average prices. Results are reported in Table 3.

| Table 3: Revenue-maximizing prices | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Period | Type of Hour | Firm | | | | | | | SMP |
| | | EN | IB | UF | HC | VI | GN | RP | |
| | All hours | 4.189 | 3.681 | 2.338 | 2.773 | 2.039 | 1.753 | 0.754 | 3.214 |
| 2001 – 2004 | Peak | 5.714 | 6.477 | 3.109 | 3.509 | 2.654 | 2.161 | 0.972 | 3.919 |
| | Off-peak 1 | 5.148 | 5.075 | 2.958 | 3.429 | 2.465 | 2.114 | 0.894 | 3.805 |
| | Off-peak 2 | 3.374 | 2.384 | 1.853 | 2.277 | 1.690 | 1.479 | 0.637 | 2.669 |
| | All hours | 5.386 | 3.685 | 2.369 | 2.904 | | | | 3.588 |
| 2001 | Peak | 8.124 | 7.792 | 3.730 | 4.154 | | | | 4.948 |
| | Off-peak 1 | 6.892 | 5.094 | 3.091 | 3.683 | | | | 4.317 |
| | Off-peak 2 | 4.205 | 2.360 | 1.797 | 2.318 | | | | 2.873 |
| | All hours | 4.704 | 5.091 | 2.743 | 3.265 | 3.156 | 1.728 | | 3.868 |
| 2002 | Peak | 6.757 | 9.272 | 3.690 | 4.212 | 4.039 | 1.896 | | 4.814 |
| | Off-peak 1 | 5.719 | 7.129 | 3.470 | 4.012 | 3.860 | 2.073 | | 4.567 |
| | Off-peak 2 | 3.748 | 3.161 | 2.164 | 2.674 | 2.602 | 1.509 | | 3.191 |
| | All hours | 3.351 | 2.966 | 2.154 | 2.467 | 2.305 | 2.668 | 1.381 | 2.851 |
| 2003 | Peak | 4.289 | 4.763 | 2.696 | 2.965 | 2.726 | 3.146 | 1.601 | 3.268 |
| | Off-peak 1 | 4.023 | 4.168 | 2.802 | 3.135 | 2.889 | 3.325 | 1.666 | 3.427 |
| | Off-peak 2 | 2.798 | 1.955 | 1.696 | 2.007 | 1.905 | 2.217 | 1.184 | 2.367 |
| | All hours | 3.035 | 2.006 | 1.754 | 2.118 | 1.935 | 2.371 | 2.095 | 2.754 |
| 2004 | Peak | 4.052 | 2.943 | 2.134 | 2.528 | 2.316 | 2.820 | 2.498 | 3.269 |
| | Off-peak 1 | 3.676 | 2.402 | 1.924 | 2.361 | 2.075 | 2.663 | 2.412 | 3.177 |
| | Off-peak 2 | 2.403 | 1.536 | 1.558 | 1.873 | 1.757 | 2.086 | 1.807 | 2.359 |

The prices in Table 3 suggest that larger generators consistently would maximize revenues at higher prices than the observed system marginal price ($\text{SMP}_h$). For smaller generators the result is just the opposite: revenue-maximizing prices are below the $\text{SMP}_h$.

## 5 Profit-maximizing price and quantity

In this section we consider the problem of profit maximization. We build a cost structure based on the unit cost of production of the different types of technologies used in generation. In general the low cost technologies are hydroelectric and nuclear. The fuel gas and combined cycle come second in the merit order, followed by coal-burning plants. Thus, the cost function is,

$$C^f\left(q_h^f\right)=\begin{cases} 0 & \text{if} \quad q_h^f=q_h^{hy}+q_h^{nu}; q_h^{hy}\leq K^{hy}, q_h^{nu}\leq K^{nu} \\ c_1^f\left(q_h^{fg}+q_h^{cc}\right) & \text{if} \quad q_h^f=q_h^{hy}+q_h^{nu}+q_h^{fg}+q_h^{cc}; q_h^{fg}\leq K^{fg}, q_h^{cc}\leq K^{cc} \\ c_1^f\left(q_h^{fg}+q_h^{cc}\right)+c_1^f\left(q_h^{co}\right) & \text{if} \quad q_h^f=q_h^{hy}+q_h^{nu}+q_h^{fg}+q_h^{cc}+q_h^{co}; q_h^{co}\leq K^{co} \end{cases}$$

where $hy$ stands for the energy produced from hydro resources, $nu$ stands for nuclear, $fg$ for fuel-gas, $cc$ for combined cycle, $co$ for coal, $K^i$ denotes capacity of the plant for that type of technology.

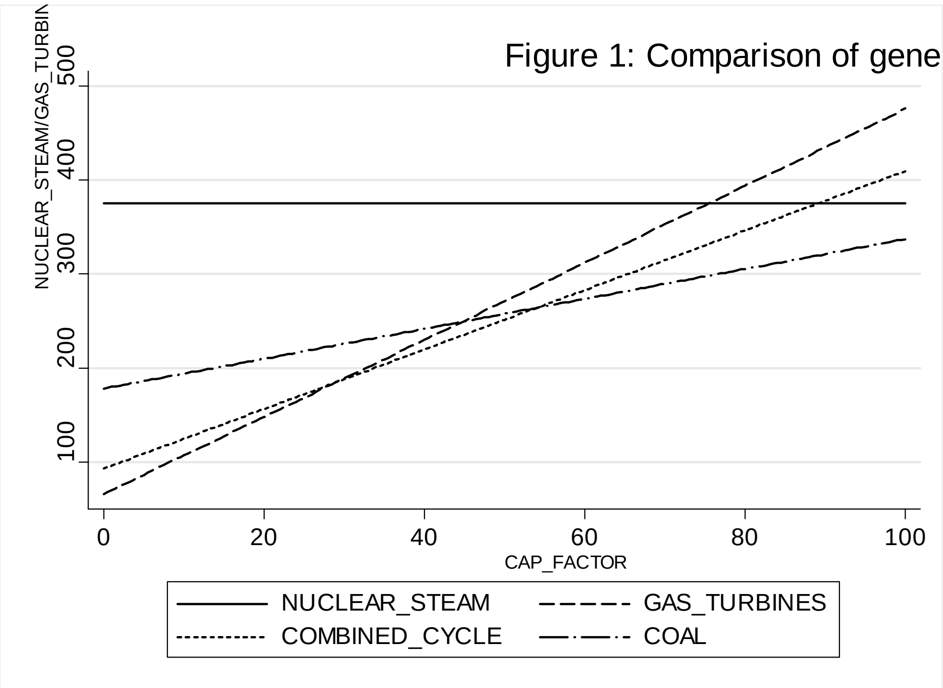
Therefore the problem to solve is,

$$\max_{p_h^f,} \quad p_h^f D_h^{r,f}\left(p_h^f\right)-C^f\left(D_h^{r,f}\left(p_h^f\right)\right)$$

where the cost function is given in the above expression.

As it is widely recognized, it is a crucial problem to estimate cost functions. We proceed by using different approaches to test the consistency of the results on profit-maximizing prices obtained according to the cost schedule we use. First, we approximate the cost function using screening curves for each type of technology. In a screening curve, a technology's total generation cost per kilowatt-year of electricity is plotted against different values of the capacity available by each plant. The generation cost includes raw materials as well as another variable costs that increase with the power generated, as well as fixed costs (capital costs) that have to be recovered during a sufficiently long period of time (usually 20 to 30 years). The capacity factor is the percentage of hours that the plant runs during a given year. A plant of any type has low generation cost if it operates many hours per year, since it allows to spread the fixed cost among more units of production.

Screening curves provides a comparisson for the use of different technologies for a given capacity factor. The slope of the curve measures the increase in annual cost for an increase in one unit of capacity use. Therefore since it is constant it can be used as an approximation for the unit cost.of generation per year.




We include a picture with the screening curves for four types of technologies: nuclear, coal, fuel-gas and combined cycle.

Results are reported in Table 3.

| Table 3: Average Profit-maximizing prices | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Period | Type of Hour | Firm | | | | | | | SMP |
| | | EN | IB | UF | HC | VI | GN | RP | |
| 2001 – 2004 | All (32185) | 6.525 | 6.168 | 3.151 | 3.137 | 3.118 | 4.093 | 4.022 | 3.214 |
| | Peak (3528) | 8.321 | 9.046 | 3.866 | 3.76 | 3.638 | 4.235 | 4.202 | 3.919 |
| | Off-peak 1 (9960) | 8.016 | 8.15 | 3.735 | 3.693 | 3.581 | 4.161 | 4.197 | 3.805 |
| | Off-peak 2 (18697) | 5.391 | 4.568 | 2.705 | 2.724 | 2.773 | 4.030 | 3.895 | 2.669 |
| 2001 | All (5881) | 8.352 | 7.302 | 3.363 | 3.229 | | | | 3.588 |
| | Peak (504) | 11.886 | 12.122 | 4.648 | 4.339 | | | | 4.948 |
| | Off-peak 1 (1848) | 10.441 | 9.565 | 4.064 | 3.917 | | | | 4.317 |
| | Off-peak 2 (3529) | 6.754 | 5.429 | 2.812 | 2.754 | | | | 2.873 |
| 2002 | All (8760) | 8.277 | 9.244 | 3.662 | 3.629 | 3.607 | 4.105 | 3.824 | 3.868 |
| | Peak (1014) | 10.715 | 13.313 | 4.554 | 4.372 | 4.244 | 4.574 | 4.51 | 4.814 |
| | Off-peak 1 (2698) | 10.776 | 12.588 | 4.389 | 4.26 | 4.163 | 4.459 | 4.439 | 4.567 |
| | Off-peak 2 (5048) | 6.452 | 6.639 | 3.089 | 3.143 | 3.182 | 3.823 | 3.358 | 3.191 |
| 2003 | All (8760) | 5.124 | 5.006 | 2.939 | 2.951 | 2.968 | 4.541 | 4.282 | 2.851 |
| | Peak (1014) | 6.955 | 7.372 | 3.46 | 3.354 | 3.222 | 4.25 | 4.095 | 3.268 |
| | Off-peak 1 (2714) | 6.218 | 6.581 | 3.502 | 3.465 | 3.342 | 4.347 | 4.248 | 3.427 |
| | Off-peak 2 (5032) | 4.166 | 3.679 | 2.53 | 2.591 | 2.716 | 4.703 | 4.338 | 2.367 |
| 2004 | All (8784) | 4.949 | 3.487 | 2.712 | 2.754 | 2.687 | 4.196 | 4.474 | 2.754 |
| | Peak (996) | 5.471 | 4.896 | 3.183 | 3.256 | 3.034 | 3.767 | 3.872 | 3.269 |
| | Off-peak 1 (2700) | 5.404 | 4.323 | 3.081 | 3.2 | 2.955 | 3.791 | 4.039 | 3.177 |
| | Off-peak 2 (5088) | 4.605 | 2.795 | 2.423 | 2.418 | 2.478 | 4.495 | 4.823 | 2.359 |

We test whether the profit-maximizing prices for the firms are significantly different from the observed equilibrium prices. The null hypothesis of equal means is rejected for EN, IB, GN and RP, but it is not rejected for UF, HC and VI. Note that the profit maximizing price is decreasing over time due to the entry of new competitors.

# 6 Intraday-market Behavior

The intra-day market is the one for adjustments in the daily viable schedule through the submittal of power sale and purchase bids to the market operator. It operates like the day-ahead market. A price is determined to clear the market. The market is divided into at least six sessions. Bids can also be simple or complex as in the day-ahead market.

The demand schedule is constructed using bids from plants that do not fulfill their required levels of power to match their bids in the day-ahead market, whereas the supply schedule is constructed using bids from

Figure 2 illustrates typical demand and supply functions.for the first session.

[Insert figure 3]

In table 4 we report the inverse elasticities for the first session of the intraday market, which is the one with the highest power trade among the six markets.

**Table 4: Inverse elasticity of residual demand, intra-day market**

| Arc | YEAR | FIRM | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | EN | IB | UF | HC | VI | GN | RP |
| | 2001 | 0.51 | 0.40 | 0.66 | 0.16 | – | – | – |
| $\pm 0.1MWh$ | 2002 | 0.68 | 1.09 | 0.68 | 0.33 | 0.38 | 0.38 | 0.38 |
| | 2003 | 0.34 | 0.44 | 0.19 | 0.14 | 0.18 | 0.22 | 0.18 |
| | 2004 | | | | | | | |
| | 2001 | 0.40 | 0.30 | 0.24 | 0.12 | – | – | – |
| $\pm 1MWh$ | 2002 | 0.55 | 0.52 | 0.30 | 0.28 | 0.36 | 0.35 | 0.36 |
| | 2003 | 0.28 | 0.34 | 0.16 | 0.13 | 0.15 | 0.17 | 0.15 |
| | 2004 | 0.25 | 0.17 | 0.10 | 0.06 | 0.06 | 0.07 | 0.06 |
| | 2001 | 0.34 | 0.23 | 0.21 | 0.10 | – | – | – |
| $\pm 10MWh$ | 2002 | 0.42 | 0.39 | 0.21 | 0.20 | 0.24 | 0.23 | 0.23 |
| | 2003 | 0.23 | 0.29 | 0.14 | 0.12 | 0.14 | 0.15 | 0.13 |
| | 2004 | 0.21 | 0.15 | 0.08 | 0.05 | 0.05 | 0.06 | 0.05 |

Notice how.the inverse elasticities of the residual demand in the intra-day market are below 1. This result follows from the fact that these markets represent a small fraction of the total energy traded. Therefore, firms do not have the same incentives to exercise market power as they have for large trades.

# 7 Concluding Comments

Our results suggest that large firms do not submit profit-maximizing bids; higher system marginal price would increase larger generators' profits. Hortacsu and Puller (2004) found the opposite result for the Texas market: In their case the largest seller offered bids which were consistent with profit maximization and smaller sellers seemed to deviate from this behavior.

A major problem we face is to gather reliable data on costs. We use screening curves as an initial approach because since the results are average yearly prices, it also seems reasonable to consider cost data on a yearly basis that smooth the curve. We consider the paper would not be entire satisfactory if we do not try different approaches to obtain cost functions and then test the robustness of the profit-maximizing prices on residual demands.

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# 9 Appendix1: The Spanish pool

The Spanish day-ahead market for electricity started its operations in January 1998.[11] Everyday qualified buyers and sellers of electricity present their offers for each hour of the following day.

Sellers in the pool present bids consisting of up to 25 different prices and the corresponding energy quantities for each of the 24 periods and for each generating unit they own; the prices must be increasing.[12] If no restriction is included in the offer this is called a 'simple offer'. A seller may also present a 'complex offer' which may include indivisibility conditions, a minimum revenue condition, production capacity variation (load gradient conditions) and scheduled stop conditions. The pool administrator consolidates the sales bids for each hourly period to generate an aggregate supply curve.

Qualified buyers in the pool present offers.[13] Purchase bids state a quantity and a price of a power block and there can be as many as 25 power purchasing blocks for the same purchasing unit, with different prices for each block; the prices must be decreasing. The pool administrator constructs an aggregate demand with these offers.

In a session of the day-ahead market the pool administrator combines these offers matching demand and supply for each of the 24 hourly periods and determines the equilibrium price for each period (the system marginal price) and the amount traded. After this matching is settled, the pool administrator evaluates the technical feasibility of the assignment; if the required technical restrictions are met then the program is feasible; if not, some previously accepted offers are eliminated and others included to obtain a feasible assignement. There is also an intra-day market to make any necessary adjustments between demand and supply. There are at the most six sessions of the intra-day market.

[11] After Act 54/1997 liberalizing the market was approved in November 1997 and Act 2019/1997 established the rules of the production market.

[12] According to the Electricity Market Activity Rules, p. 6, generators "shall be required to submit electric power sale bids to the market operator for each of the production units they own for each and every one of the hourly scheduling periods."

[13] >From January 1st 2003, all buyers of electricity are considered qualified buyers. Before that date qualified buyers were those with consumption greater or equal to 1 GWh per year. The required consumption has decreased over time from 5GWh (December 1998) to 3GWh (April 1999), to 2GWh (July 1999) and to 1 GWh (October 1999).

# 10 Apéndice 2: Kernel densities review

A kernel density estimate is formed by summing the weighted values calculated with the kernel density function $K$,

$$\widehat{f}_K = \frac{1}{nh} \sum_{i=1}^{n} K\left(\frac{x - X_i}{h}\right)$$

where $n$ is the total number of observations, $h$ is the bandwith, and the function $K$ is chosen as to minimize the mean integrated square error. There are two choices to take when using this type of non-parametric estimators: The smoothing function, $K(\cdot)$, and the bandwith, $h$. We consider the Epanechnikov function of the form,

$$K\left(\frac{x - X_i}{h}\right) = \begin{cases} \frac{3}{4\sqrt{5}}\left(1 - \frac{1}{5}\left(\frac{x-X_i}{h}\right)^2\right) & \text{if } \left|\frac{x-X_i}{h}\right| < \sqrt{5} \\ 0 & \text{otherwise} \end{cases}$$

We take as bandwith,

$$h = \frac{0.9m}{n^{1/5}} \text{ where } m = \min\left(\sigma_x, \frac{igr_x}{1.349}\right)$$

where $igr_x$ is the interquartile range of $x$, that is the difference between the 75th percentile and the 25th percentile.

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